

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION)	CASE NO. PAC-E-15-01
OF ROCKY MOUNTAIN POWER FOR)	
AUTHORITY TO INCREASE RATES BY)	DIRECT TESTIMONY OF
\$10.7 MILLION TO RECOVER)	MICHAEL WILDING
DEFERRED NET POWER COSTS)	
THROUGH THE ENERGY COST)	
ADJUSTMENT MECHANISM)	

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-15-01

February 2015

1 **Q. Please state your name, business address and present position with**
2 **PacifiCorp, dba Rocky Mountain Power (the “Company”).**

3 A. My name is Michael Wilding. My business address is 825 NE Multnomah Street,
4 Suite 600, Portland, Oregon 97232. My title is Senior Net Power Cost Analyst.

5 **Qualifications**

6 **Q. Briefly describe your education and business experience.**

7 A. I received a Master of Accounting from Weber State University and a Bachelor of
8 Science degree in accounting from Utah State University. I am a Certified Public
9 Accountant licensed in the state of Utah. Prior to joining the Company, I was
10 employed as an internal auditor for Intermountain Healthcare and an auditor for
11 the Utah State Tax Commission. I have been employed by the Company since
12 February 2014.

13 **Summary of Testimony**

14 **Q. What is the purpose of your testimony in this proceeding?**

15 A. My testimony presents and supports the Company’s calculation of the Energy
16 Cost Adjustment Mechanism (“ECAM”) balancing account for the twelve-month
17 period from December 1, 2013 through November 30, 2014 (“Deferral Period”).

18 More specifically, my testimony provides the following:

- 19 • A summary of the ECAM calculation, including changes made to comply with
20 recent Commission orders.
- 21 • Details supporting the addition of \$16.6 million (“2014 Deferral”) to the
22 deferral balance, bringing the total balance to \$27 million as of November 30,
23 2014.

- 1 • Additional details of the ECAM calculation and a description of the
2 Company's net power costs ("NPC").

3 **Q. Are additional witnesses presenting testimony in this case?**

4 A. Yes. Ms. Joelle R. Steward, Director, Pricing, Cost of Service & Regulatory
5 Operations, is sponsoring testimony supporting the Company's proposed ECAM
6 collection rates in Schedule 94. The Company is proposing to modify Electric
7 Service Schedule No. 94, Energy Cost Adjustment, effective April 1, 2015, to
8 collect approximately \$23.3 million on an annual basis as compared to the current
9 collection rate of approximately \$12.7 million.

10 **Summary of the ECAM Deferral Calculation**

11 **Q. Please briefly describe the Company's ECAM authorized by the**
12 **Commission.**

13 A. In general, the ECAM tracks deviations between actual NPC and the NPC in base
14 rates and defers 90 percent of the difference for later recovery.¹ Other items which
15 I describe in detail later in my testimony, include sales of sulfur dioxide ("SO₂")
16 emission allowances, load control or demand side management ("DSM") costs,
17 and revenues from the sale of renewable energy credits ("RECs"), are also tracked
18 in the ECAM to true-up the amount in base rates to actuals. The balance that
19 accumulates over a deferral period is then passed on to customers as a rate
20 surcharge or credit. The ECAM Schedule 94 rate, which appears as a separate line
21 item on customer bills, collects from or credits to customers the balance of
22 deferred costs. Schedule 94 is adjusted as needed in the Company's annual

¹ Order No. 30904 in Case No. PAC-E-08-08 approved the stipulation entered into by the Commission Staff, the Idaho Irrigation Pumpers Association, Monsanto and the Company that set up the structure and content of the ECAM mechanism.

1 ECAM filings. The annual deferral period for the ECAM is December 1 to
2 November 30. The Company is required to file an application with the
3 Commission by February 1 of each year to seek approval of the deferral amount
4 and to adjust the ECAM rate effective April 1.

5 **Q. How are the 2015 ECAM deferral calculations presented in your testimony?**

6 A. The calculation of the 2015 ECAM deferral is contained in Exhibit No. 1. A
7 summary of the major components is contained in Table 1 below. Later in my
8 testimony I discuss the details of the calculations contained in Exhibit No. 1.

9 **Q. What changes to the ECAM calculation have been implemented to comply**
10 **with Commission orders from previous cases?**

11 A. Consistent with the stipulation approved in Order No. 32910, Case No. PAC-E-
12 13-04, beginning December 1, 2013, the ECAM is calculated on a total Idaho
13 basis; Monsanto and Agrium's share were not calculated separately. However,
14 separate deferral accounts have been maintained to properly account for pre-
15 December 2013 balances. Pursuant to Order No. 33008 in Case No. PAC-E-14-
16 01, the Company implemented Staff's back cast calculation to perform a check
17 for over/under-collection of NPC, load control costs, and RECs.

18 Lake Side 2 began commercial operation in May 2014, so beginning
19 January 1, 2015, pursuant to the stipulation in Case No. PAC-E-13-04, the ECAM
20 will include a resource adder to recover the investment in the new Lake Side 2
21 generation facility until it is reflected in rates as a component of rate base. The
22 ECAM deferral will be based on the Lake Side 2 actual generation multiplied by
23 \$1.99/MWH, and capped at a total of \$5.43 million or 2,729,500 MWh.

1 **2014 Deferral**

2 **Q. Please describe the ECAM components that make up the 2014 Deferral.**

3 A. The 2014 Deferral is the sum of customers' 90 percent share of the following
4 items: the difference between the actual and in-rates NPC, the Load Change
5 Adjustment Revenue ("LCAR"), the SO₂ allowance sales, the load control cost
6 adjustment, and the Emerging Issues Task Force ("EITF") 04-6 coal cost
7 adjustment. An additional true-up of 100 percent of the revenue difference from
8 the sale of RECs is also included. Consistent with the Commission's order in Case
9 No. PAC-E-14-01, a back cast adjustment is made to the ECAM balance to
10 account for any over- or under-collection of NPC, load control costs, and RECs.
11 Detailed calculations are provided in Exhibit No. 1, attached to my testimony, and
12 Table 1 below summarizes the various components of the deferral.

Table 1

	<u>Idaho Customers</u>
NPC Differential for Deferral	\$12,735,507
LCAR	(619,086)
SO ₂	(71)
Irrigation Load Control	963,027
EITF 04-6 Adjustment	(66,928)
Total Deferral Before Sharing	13,012,449
Sharing Band	90%
Customer Reponsibility	\$11,711,204
REC Deferral	6,064,558
Back-Cast Adjustments	(1,247,334)
Interest	106,134
Total Company Recovery for NPC Deferral	\$16,634,562

13 **Q. Please explain the calculation of the ECAM balance for the Deferral Period.**

14 A. Table 1 summarizes the components of the ECAM balance. The first section
15 summarizes the Idaho-allocated share of those items for which Idaho customers
16 and the Company share responsibility including: NPC differential, LCAR, SO₂

1 sales, irrigation load control costs, and the EITF 04-6 adjustment. The next
2 section calculates the 90 percent customers' share of those items and adds the
3 Idaho-allocated REC revenue true-up or difference, for which customers are
4 refunded or surcharged 100 percent. The back cast adjustment is added to assure
5 there is no over or under-collection of NPC, irrigation load control, and revenues
6 from the sale of RECs. The total of these items represents the 2014 Deferral. The
7 2014 Deferral of \$16.6 million is a result of the \$11.7 million customers' share of
8 the NPC differential, including the adjustments for LCAR, SO₂ sales, load control
9 costs and EITF 04-6, and the \$6.1 million REC revenue differential. The back cast
10 adjustment reduces the 2014 Deferral by the \$1.2 million. The remaining \$0.1
11 million is interest accrued on the 2014 Deferral.

12 **Q. Based on your calculations, what is the balance expected to be in the ECAM**
13 **deferral account as of April 1, 2015?**

14 A. The projected balance of the ECAM Balancing Accounts as of April 1, 2015 is
15 \$23.3 million. Table 2 summarizes the balancing account's activity starting with
16 the \$23.7 million balance in the ECAM deferral account as approved in Case No.
17 PAC-E-14-01. That balance is adjusted for collections and interest accrued during
18 the Deferral Period, and an adjustment was made for the Wholesale Loss
19 Adjustment required by Order 33094. The 2014 Deferral is added to the deferral
20 account for all Idaho customers, and as noted above separate deferral accounts for
21 Agrium and Monsanto have been maintained to properly account for pre-
22 December 2013 balances. The estimated deferral account balance of \$23.3 million
23 due for collection as of April 1, 2015, consists of Monsanto's outstanding balance

of approximately \$6.2 million, Agrium's outstanding balance of \$0.5 million, Tariff Customers' outstanding balance of approximately \$69,000, and the \$16.6 million from the Deferral Period which will be due from all Idaho customers.

Table 2
Balancing Account Activity

	All Idaho Customers	Tariff Customers	Monsanto	Agrium	Total
Balancing Account Activity					
Prior Deferral		\$9,535,217	\$13,170,906	\$997,651	\$23,703,774
ECAM Revenue Collection		(7,760,018)	(5,392,477)	(393,865)	(13,546,360)
Interest		53,267	107,621	8,198	169,085
WLA Adjustment per Order 33094		(67,500)	63,000	4,500	-
Activity Through November 30, 2014		\$1,760,965	\$7,949,050	\$616,484	\$10,326,500
November 30, 2014 Balance For Collection	\$16,634,562	\$1,760,965	\$7,949,050	\$616,484	\$26,961,062
Schedule 94 Collection - Dec 2014 - March 2015		(\$1,694,726)	(\$1,797,427)	(\$156,693)	(\$3,648,846)
Interest		2,938	23,624	1,785	28,348
Expected Balance as of April 1, 2015	\$16,634,562	\$69,178	\$6,175,247	\$461,577	\$23,340,564

Q. What is the proposed collection amount due from customers under Schedule 94 beginning April 1, 2015?

A. Schedule 94 was designed to collect \$23.3 million as explained in the testimony of Company witness Ms. Steward. The Company proposes to collect approximately \$16.6 million from all Idaho customers beginning April 1, 2015. In addition the ECAM rate for Monsanto and Agrium will be designed to collect the prior year balances of approximately \$6.6 million. Ms. Steward's testimony details the rate impact of the updated ECAM collections.

Summary of the NPC Differences

Q. Please explain the difference between adjusted actual NPC ("Actual NPC") and the NPC in base rates ("Base NPC").

A. On a total Company basis, Actual NPC for the Deferral Period were approximately \$1.639 billion. During the Deferral Period, the Base NPC in rates

1 originated from the 2011 Rate Case. The stipulation approved in that case
2 established Base NPC of \$1.385 billion for 2013 and per Order No. 32910 in Case
3 No. PAC-E-13-04 the 2013 base has remained in place during 2014 for the
4 ECAM.

5 **Q. Did the Company anticipate that actual NPC would be higher than the NPC**
6 **included in rates during the Deferral Period?**

7 A. Yes. In June 2013 the Company reached an agreement with multiple parties in
8 Case No. PAC-E-13-04 establishing an alternative rate plan in lieu of filing
9 another general rate case. Mr. J. Ted Weston's testimony filed in support of that
10 stipulation indicated that the rates currently in effect justified a price increase,
11 primarily driven by three factors: higher actual net power costs, lower REC
12 revenues, and increased depreciation expense.² The first two factors are the main
13 drivers of the difference in costs in the Deferral Period. Mr. Weston explained that
14 the potential to recover increased actual NPC and lower REC revenue through the
15 ECAM enabled the Company to delay the rate case anticipated in 2013 and to pursue
16 and execute the alternative rate plan.³

17 **Q. Did parties to the stipulation understand the impact these settlements would**
18 **have on the ECAM?**

19 A. Yes. As noted by Mr. Weston the parties supported this approach knowing they
20 would benefit from the delay in paying the higher level of net power costs.

² Case No. PAC-E-13-04, Stipulation Testimony of J. Ted Weston at 3-4.

³ Case No. PAC-E-13-04, Stipulation Testimony of J. Ted Weston at 9-10.

1 Q. Has the Company provided quarterly ECAM reports as directed by the
2 Commission in Case No. PAC-E-12-03?

3 A. Yes. The Company has provided preliminary ECAM calculations on a quarterly
4 basis to enable ongoing analysis of the ECAM. The last quarterly report, provided
5 for the period December 2013 through August 2014, reported an incremental NPC
6 deferral of \$11.7 million and a REC adjustment of \$4.5 million.

7 Q. What are the major drivers that result in a difference between Actual NPC
8 and Base NPC?

9 A. The \$254 million difference on a total company basis between Base NPC and
10 Actual NPC during the Deferral Period is summarized in Table 3 below by the
11 major categories in the NPC report.

Table 3
Deferral Period NPC Reconciliation (\$millions)

	EBA Deferral Period
ID Base NPC 2011 GRC PAC-E-11-12	\$1,385
Increase/(Decrease) to NPC:	
Wholesale Sales	374
Purchased Power	(181)
Coal Generation	108
Gas Generation	19
Wheeling Hydro and Other	7
Total Increase/(Decrease)	\$327
Settlement Adjustment	(73)
Total Company NPC Difference	\$254
Adjusted Actual NPC 2014	\$1,639

12 An apples-to-apples comparison of Base NPC and Actual NPC is difficult
13 due to the disparity in timing between the test period used to determine Base NPC
14 in the 2011 Rate Case and the period over which those rates have been in effect.

1 Base NPC were set using a calendar year 2011 test period and the settlement in
2 the 2011 Rate Case included a "black box" adjustment to determine Base NPC.

3 **Q. Notwithstanding the issues you describe above, can you explain some of the**
4 **differences in NPC categories?**

5 A. Yes. The major contributor to the variance in NPC is a reduction in wholesale
6 sales revenue. The increase in NPC due to lower wholesale sales and higher coal
7 and gas fuel expenses is partially offset by reduced purchased power expenses.
8 Higher load and lower wind and hydro generation also contributed to higher costs
9 compared to Base NPC, with the impact of each spread across multiple cost
10 categories.

11 **Q. Please explain the reduction in wholesale sales revenue.**

12 A. The reduction in wholesale sales revenue is driven by the expiration of four long-
13 term sales contracts and reduced revenue from short-term wholesale market sales.
14 Wholesale sales contracts with Nevada Power, Pacific Gas and Electric, Public
15 Service Company of Colorado, and Southern California Edison were included in
16 Base NPC but have since expired. Expiration of these contracts accounted for \$73
17 million reduction in wholesale sales revenue and a 2.1 million MWh reduction in
18 sales volume. This reduction in sales is partially offset by the addition of the sales
19 contract with Shell Energy which accounted for \$8 million of wholesale sales
20 revenue and 0.2 million MWh of sales volume. The expiration of these long-term
21 contracts account for about 17 percent of the reduction in wholesale sales
22 revenues.

23 Revenue from market transactions (represented in the Company's

1 production dispatch model ("GRID") as short-term firm and system balancing
2 sales) is approximately \$307 million lower than Base NPC. The drop in revenue is
3 due to both the volume variance and the average price of market sales
4 transactions. The market sales transactions in the Base NPC were 2,927 GWh
5 higher than actual market sales transactions during the Deferral Period at an
6 average price of \$52.43/MWh compared to actual market sales during the
7 Deferral Period at an average price of \$32.69/MWh. The drop in wholesale
8 market price alone accounts for about 51 percent of the reduction in wholesale
9 sales revenues.

10 **Q. Please explain the reduction in purchased power expense.**

11 A. Similar to wholesale sales, the reduction in purchased power expense is driven by
12 the expiration of several long-term contracts and reduced expenses from
13 wholesale market purchases. Long term contracts expiring prior to the end of the
14 Deferral Period include purchases from Grant County Public Utility District
15 ("PUD"), Chelan County PUD, Black Hills Power, and Roseburg Forest Products;
16 a Kennebec generation incentive; two call options with Morgan Stanley; and a
17 peaking contract with the Bonneville Power Administration. The expiration of
18 these contracts accounts for a reduction of approximately \$72 million in
19 purchased power expense. In addition, expenses related to several qualifying
20 facility ("QF") contracts decreased approximately \$60 million due to customers'
21 QF generation serving their own load. The loss of the energy from these long-
22 term contracts contributed to the lower wholesale sales volumes previously noted.

23 Expenses from market transactions (represented in GRID as short-term

1 firm and system balancing purchases) are approximately \$111 million lower than
2 Base NPC. This drop in expenses is due mainly to reduced volume of market
3 purchases, partially offset by an increase in the average price of market purchase
4 transactions.

5 **Q. Are there any new long term purchase contracts that partially offset the**
6 **overall reduction in purchased power expense?**

7 A. Yes. There are five new wind and one geothermal QFs that had little or no
8 generation in Base NPC, increasing purchased power expense approximately
9 \$33.3 million. These include the Power County North and South QFs which came
10 online at the end of 2011, the Roseburg Dillard QF came online at the beginning
11 of 2012, the Five Pine and North Point QFs which came online at the end of 2012,
12 and the Foote Creek III that began selling power to the Company at the end of
13 2014. The Company also executed a purchase agreement with Constellation
14 Energy to purchase seasonal power during summer peak months.

15 **Q. Please explain the change in coal fuel expense.**

16 A. Coal generation volume was relatively unchanged compared to the Base NPC,
17 increasing by only 210 GWh (0.5 percent). However, the average cost of coal
18 generation increased from \$16.60/MWh in Base NPC to \$19.09/MWh in the
19 Deferral Period, contributing to an overall increase of \$108 million in coal fuel
20 expense. Base NPC was set in 2011 and there have been some notable changes
21 that have affected coal fuel costs including contractual coal price increases, new
22 coal contracts, and increased mine operating costs at the Bridger and Deer Creek
23 mines.

1 **Q. Please explain the change in natural gas fuel expense.**

2 A. The actual natural gas fuel expense was \$19 million greater than the natural gas
3 fuel expense in rates. This difference is a result of an increase in natural gas
4 generation volume of 4,647 GWh or 77 percent above Base NPC. The Lake Side
5 2 combined cycle combustion turbine plant reached commercial operation during
6 the Deferral Period increasing gas generation approximately 1,472 GWh. The
7 remaining increase in natural gas generation volume occurred mainly at the
8 Company's Lake Side 1 and Chehalis plants. Lake Side 1 generated more due to
9 more favorable economics in the Deferral Period when compared to the Base
10 NPC study. Starting in December 2013, the Chehalis plant moved to the
11 Company's balancing authority area and was able to provide reserves during the
12 Deferral Period, causing it to be operated more than previously modeled in GRID
13 where it was not able to provide reserves.

14 **Q. How did changes in load and hydro and wind generation impact NPC?**

15 A. Actual system load during the Deferral Period was 2,153 GWh (four percent)
16 higher than the load in Base NPC, and hydro generation in the Deferral Period
17 was 394 GWh (10 percent) lower than in Base NPC. The impact of higher load
18 and lower hydro and wind generation is spread across the different NPC
19 components, and contributes to the reduced wholesale sales revenue shown in
20 Table 3.

21 **Description of the ECAM Calculations**

22 **Q. Please describe the ECAM calculations in your Exhibit No. 1.**

23 A. The ECAM deferral is calculated by comparing the Actual NPC to the Base NPC

1 on a monthly basis and deferring the differences into an ECAM balancing
2 account. The deferral amount is the difference in the system dollar-per-megawatt-
3 hour rate multiplied by the Idaho retail load. Exhibit No. 1 includes details of the
4 ECAM calculation and the confidential workpapers contain supporting
5 information.

6 **Q. How are the Base NPC and Actual NPC dollar-per-megawatt-hour rates**
7 **calculated?**

8 A. The monthly NPC for Base NPC are divided by the corresponding monthly
9 normalized load to express the costs on a dollar-per-megawatt-hour basis, as set
10 forth in Exhibit No. 1, line 1. The Actual NPC rate on a dollar-per-megawatt-hour
11 basis is calculated by dividing the monthly Actual NPC in the Deferral Period by
12 the actual monthly system load in the Deferral Period, as set forth in Exhibit No.
13 1, line 8. On a dollar-per-megawatt-hour basis, the Base NPC average is
14 \$23.73/MWh, and the Actual NPC averaged \$27.05/MWh, or \$3.32 /MWh
15 higher.

16 **Q. Please describe how the NPC deferral is calculated.**

17 A. The deferral is calculated on a monthly basis by subtracting the Base NPC rate
18 from the Actual NPC rate. The resulting monthly NPC rate differential (Exhibit
19 No. 1, line 9) is then multiplied by the actual Idaho retail load at input (Exhibit
20 No. 1, line 10) to calculate the NPC differential for deferral (Exhibit No. 1, line
21 12). For the 12-month period ended November 2014 the NPC differential was
22 approximately \$12.7 million before application of the 90 / 10 percent sharing.

- 1 • legal fees included in the cost of coal related to fines and citations;
- 2 • the true-up of coal inventories;
- 3 • the true-up of energy returned to a third party to compensate for prior line
- 4 losses;
- 5 • revenue imputation of the sales contract with the Sacramento Municipal
- 6 Utility District; and
- 7 • revenue associated with the Company's Leaning Juniper facility due to a
- 8 contract unique to that wind project.

9 **Q. What is an out of period accounting entry?**

10 A. Out of period accounting entries are items booked during the Deferral Period that
11 pertain to an operating period prior to the inception of the ECAM on July 1, 2009.

12 **Q. Why is the July 1, 2009 cutoff used to determine out of period entries?**

13 A. Since the ECAM took effect, customers' rates have been adjusted to recover
14 essentially all of the Company's actual net power costs, excluding any differences
15 due to the 90 / 10 percent sharing band. Consequently, any accounting entries
16 made during the current Deferral Period that relate to any operating period since
17 the ECAM took effect should also be reflected in customer rates, whether they
18 increase or decrease Actual NPC. Accounting entries related to operating periods
19 prior to the inception of the ECAM should not impact the ECAM deferral.

20 **Q. In addition to the comparison of Actual NPC to Base NPC, what other**
21 **components are included in the ECAM?**

22 A. There are six additional components included in the ECAM calculations: (i) the
23 LCAR adjustment (ii) a credit for any SO₂ allowance sales, (iii) a true-up of load

1 control costs, (iv) an adjustment for deferred costs associated with coal mine
2 stripping activities recorded under the Financial Accounting Standards Board
3 ("FASB") EITF 04-6, (v) a true-up of REC revenues as authorized by the
4 Commission in Order No. 32196, (vi) and a back cast adjustment that accounts for
5 any over- or under-collection of NPC, load control costs, and REC revenues.

6 **Q. Please describe the LCAR adjustment.**

7 A. The calculation of the LCAR adjustment is a symmetrical adjustment for over- or
8 under-collection of the energy-related portion of the Company's embedded
9 revenue requirement for production facilities as specified in Case No. GNR-E-10-
10 03, Order No. 32206. The LCAR accounts for variances in Idaho load that cause
11 the Company to collect more or less of these production-related costs. The LCAR
12 rate was last set in Order No. 32432 at \$5.47 per megawatt-hour. This rate has
13 been in effect since April 1, 2011.

14 **Q. How is the LCAR adjustment calculated and what is the impact on the 2013**
15 **Deferral?**

16 A. The LCAR adjustment is calculated by subtracting the Idaho load at input
17 established in rates ("Base Load" shown in Exhibit No. 1, line 13), from actual
18 Idaho load at input ("Actual Load" shown in Exhibit No. 1, line 14). The
19 difference (Exhibit No. 1, line 15) is then multiplied by the LCAR rate of \$5.47
20 per megawatt-hour in all months of the Deferral Period (Exhibit No. 1, line 16) to
21 arrive at the LCAR adjustment (Exhibit No. 1, line 17) resulting in a \$619,086
22 decrease to the NPC deferral before the 90 / 10 percent sharing.

1 **Q. How are SO₂ sales revenues included in the ECAM?**

2 A. Line 18 of Exhibit No. 1 contains the SO₂ sales revenue during the Deferral
3 Period on a total Company basis. Line 20 of Exhibit No. 1 is Idaho's allocated
4 share of the SO₂ sales revenue which is calculated using Idaho's System Energy
5 ("SE") allocation factor authorized by the Commission from the 2011 Rate Case.
6 For the Deferral Period, the total SO₂ sales revenue credit is a \$71 reduction to the
7 NPC deferral balance before the 90 / 10 percent sharing.

8 **Q. How is the load control cost adjustment calculated in the ECAM?**

9 A. The load control cost adjustment is a comparison of actual costs for load control
10 programs compared to the base level established in the 2011 Rate Case. The
11 stipulation approved in the 2011 Rate Case established the base amount to be
12 tracked in the ECAM as \$1,045,423. Idaho-allocated actual load control costs
13 during the Deferral Period were approximately \$2 million. The difference, shown
14 on line 23 of Exhibit No. 1, is included as a \$1 million addition to the NPC
15 deferral balance before the 90 / 10 percent sharing.

16 **Q. How is the adjustment for accounting pronouncement EITF 04-6 included in**
17 **the ECAM?**

18 A. Line 24 of Exhibit No. 1 reflects Idaho's allocated differences between the coal
19 stripping costs incurred by the Company and recorded on the Company's books
20 pursuant to the guidance of the accounting pronouncement EITF 04-6, and the
21 amortization of the coal stripping costs when the coal was excavated. For the
22 Deferral Period, the total EITF 04-6 coal stripping deferral adjustment is a
23 \$66,928 decrease to the NPC deferral balance before the 90 / 10 sharing.

1 **Q. Please explain the sharing ratio between the Company and customers in the**
2 **ECAM.**

3 A. The ECAM includes a symmetrical sharing ratio in which customers either pay or
4 receive 90 percent of the ECAM deferral balance and the Company is responsible
5 for the remaining 10 percent. Line 28 of Exhibit No. 1, represents the customers'
6 90 percent share of the monthly deferral shown on line 26 of Exhibit No. 1. For
7 the Deferral Period, the customers' share of the deferred balance is approximately
8 \$11.7 million. The remaining balance of approximately \$1.3 million is not
9 included in the deferral calculation and is not recoverable from customers.

10 **Q. What is the amount of REC revenue true-up in the current filing?**

11 A. As authorized by the Commission in Case No. PAC-E-10-07, Order No. 32196,
12 the Company included the difference between actual REC revenues during the
13 Deferral Period and the amount of REC revenues included in base rates. The REC
14 revenue true-up included in the ECAM is symmetrical but no sharing band is
15 applied – the entire difference between base and actual REC revenues is either
16 refunded or surcharged to customers. Base rates during the Deferral Period
17 included \$6.5 million in Idaho-allocated REC revenue. Idaho's actual REC
18 revenues for that same time period were approximately \$0.5 million, a difference
19 of approximately \$6 million (Exhibit No. 1, line 31).

20 **Q. Please explain the back cast adjustment.**

21 A. In Case No. PAC-E-14-01, the Commission Staff developed what I refer to as a
22 back cast adjustment to check for any over- or under-collection of NPC, load
23 control costs, and REC revenue during the Deferral Period. The back cast is

1 performed by summing the NPC collected in rates and the NPC differential from
2 the ECAM before sharing. This amount is compared to actual NPC on an Idaho-
3 allocated basis, and the difference is subject to the 90 / 10 percent sharing band.
4 The same calculation is used for load control costs and REC revenue, except that
5 REC revenue is not subject to the sharing band. The total back cast adjustment
6 reduces the ECAM \$1.2 million (Exhibit No. 1, Line 35).

7 **Q. What is the total ECAM deferred balance as calculated in Exhibit No. 1?**

8 A. The total ECAM deferred balance as of November 30, 2014 is \$27 million, shown
9 on line 62 of Exhibit No. 1.

10 **Q. How is this balance divided among customers?**

11 A. Consistent with the stipulation approved in Order No. 32910 in Case No. PAC-E-
12 13-04, beginning December 1, 2013, the ECAM has been calculated on a total
13 Idaho basis; Monsanto and Agrium's share were not be calculated separately.
14 However, the balances associated with deferrals prior to December 1, 2013 have
15 continued to be identified separately and included in rates for Monsanto, Agrium,
16 and remaining tariff customers until fully recovered.

17 **Q. Does the calculation of the deferred NPC adjustment in this application**
18 **comply with the parameters of the Idaho ECAM as approved by the**
19 **Commission?**

20 A. Yes. Therefore, the Company recommends the Commission approve the ECAM
21 application for recovery of the \$16.6 million prudently incurred NPC.

22 **Q. Does this conclude your direct testimony?**

23 A. Yes.

Case No. PAC-E-15-01
Exhibit No. 1
Witness: Michael Wilding

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Michael Wilding

February 2015

Idaho ECAM Deferral
December 2013 through November 2014

Line No.	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Total
1 Base NPC Rate (\$/MWh)	23.58	21.11	21.50	20.03	22.72	22.19	22.21	27.11	28.90	27.01	24.24	24.15	
2 Total Company Adjusted Actual NPC Excl. Integration Ag (\$)	164,260,932	141,863,518	137,424,183	124,230,550	116,279,460	126,620,569	135,596,501	177,664,266	152,729,960	132,789,526	114,087,239	116,597,845	1,636,297,828
3 Intra-Hour Wind Integration Cost (\$/MWh)	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	2.31	
4 Third Party Wind sold to Wholesale (MWh)	112,840	121,367	141,992	140,690	89,479	95,284	95,284	75,588	55,871	76,711	119,714	231	2,884,850
5 Third Party Wind Adjustment	260,998	280,787	328,426	325,415	206,822	204,852	204,852	174,835	129,481	176,714	219,789	286,659	
6 Total Company Adjusted Actual NPC (\$)	163,998,934	141,582,751	137,095,768	123,905,134	116,072,638	126,415,717	135,398,353	177,839,101	152,601,479	132,613,112	113,801,008	116,301,088	1,636,412,979
7 Actual Retail Load (MWh)	5,832,244	5,361,822	4,750,460	4,786,777	4,463,549	4,654,551	4,696,197	5,697,351	5,391,311	4,814,561	4,659,695	4,809,370	60,273,593
8 Actual NPC (\$/MWh)	28.12	26.41	28.89	25.89	25.82	27.35	27.10	29.89	28.82	27.55	24.60	24.20	
9 NPC Differential \$/MWh	5.54	5.30	5.66	5.86	5.30	4.12	4.89	6.28	6.28	0.54	0.36	0.05	
10 Actual Idaho Load (MWh) for NPC Deferral	302,759	292,373	242,284	276,644	274,027	353,080	440,933	483,885	305,163	276,320	294,068	235,778	3,760,214
11 Actual Idaho NPC	8,615,167	7,720,329	7,103,706	7,162,380	7,075,040	9,290,244	11,950,452	14,613,941	8,734,431	7,608,164	6,664,706	5,704,779	102,479,340
12 Total NPC Differential for Deferral (\$)	1,797,977	1,443,045	1,333,005	1,232,224	1,237,838	1,423,646	1,717,528	2,129,646	1,423,646	1,717,528	1,423,646	1,032,242	17,938,507
13 Total Base Load for LCAF	295,208	297,401	295,371	274,579	295,376	297,966	371,303	484,962	332,085	274,965	285,452	274,247	
14 Actual Idaho Load (MWh) for LCAF	295,208	297,401	295,371	274,579	295,376	297,966	371,303	484,962	332,085	274,965	285,452	274,247	
15 Difference Base Load to Actual Load	14,189	14,189	14,189	14,189	14,189	14,189	14,189	14,189	14,189	14,189	14,189	14,189	
16 Difference Base Load to Actual Load	14,189	14,189	14,189	14,189	14,189	14,189	14,189	14,189	14,189	14,189	14,189	14,189	
17 Load Change Adjustment Revenues (LCAF)	(77,670)	(77,670)	(77,670)	(77,670)	(77,670)	(77,670)	(77,670)	(77,670)	(77,670)	(77,670)	(77,670)	(77,670)	(818,085)
18 SO2 Allowance Sales													
19 Idaho SE Factor													
20 Idaho Allocated SO2 Allowance Sales													
21 Load Control Cost Adjustment	1,797,446	841,053	2,078,008	1,819,176	1,936,647	1,237,862	2,395,838	2,395,201	1,215,709	1,756,536	(1,617,531)	(44,736)	
22 Idaho SO2 Factor	6.0525%	6.0525%	6.0525%	6.0525%	6.0525%	6.0525%	6.0525%	6.0525%	6.0525%	6.0525%	6.0525%	6.0525%	
23 Idaho Allocated Load Control Cost Adjustment	108,700	58,957	125,771	110,108	117,216	74,929	145,008	144,970	73,581	108,314	(87,307)	(2,108)	963,027
24 Idaho Allocated EITF O&E Deferral Adjustment	(23,900)	38,930	(1,024)	(16,666)	(44,333)	(16,774)	(45,233)	(13,466)	20,917	(21,418)	(3,555)	59,616	(69,928)
25 Total Adjustments (LCAF + SO2 + Load Control + EITF O&E)	1,720	118,796	87,165	82,145	(13,818)	(248,350)	(81,168)	127,688	210,245	16,123	(83,777)	264,972	216,942
26 Total NPC Differential + Total Adjustment	1,683,197	1,664,841	1,521,169	1,702,369	1,521,169	1,521,169	1,521,169	1,521,169	1,521,169	1,521,169	1,521,169	1,521,169	13,012,449
27 Customer / Company Sharing (80/10)	1,614,877	1,486,336	1,293,853	1,633,132	1,521,169	1,521,169	1,521,169	1,521,169	1,521,169	1,521,169	1,521,169	1,521,169	11,711,204
28 Customer / Company Sharing (20/80)	(140,948)	(140,948)	(140,948)	(140,948)	(140,948)	(140,948)	(140,948)	(140,948)	(140,948)	(140,948)	(140,948)	(140,948)	(140,948)
29 Idaho Actual Renewable Energy Credit Revenues (\$)	402,838	612,327	623,707	618,876	623,707	623,707	623,707	623,707	623,707	623,707	623,707	623,707	8,064,588
30 Backcast Adjustment to REC Revenues													
31 REC Revenue Adjustment (\$)													
32 Backcast Adjustment to REC Revenues													
33 Backcast Adjustment to REC Revenues													
34 Backcast Adjustment to REC Revenues													
35 Total Backcast Adjustments													
36 Interest Rate	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	
37 All Customer Balancing Account (\$)													
38 Beginning Balance		1,918,614	3,931,734	6,189,609	8,247,630	9,528,850	11,118,267	13,331,545	15,556,291	15,895,872	16,574,408	17,104,170	
39 Incremental Deferral	1,514,877	1,486,337	1,293,853	1,633,132	1,521,169	1,521,169	1,521,169	1,521,169	1,521,169	1,521,169	1,521,169	1,521,169	
40 EEC Revenue Adjustment	402,838	612,327	623,707	618,876	623,707	623,707	623,707	623,707	623,707	623,707	623,707	623,707	
41 Load Control Cost Adjustment	1,614,877	1,486,336	1,293,853	1,633,132	1,521,169	1,521,169	1,521,169	1,521,169	1,521,169	1,521,169	1,521,169	1,521,169	
42 Interest	799	2,437	4,215	7,404	8,589	10,183	11,907	12,875	12,875	13,524	14,027	14,027	
43 All Customers Deferral Balance (\$)	1,918,614	3,931,734	6,189,609	8,247,630	9,528,850	11,118,267	13,331,545	15,556,291	15,895,872	16,574,408	17,104,170	16,534,692	
44 Tariff Customer Balancing Account (\$)													
45 Beginning Balance	9,538,217	8,752,232	7,930,911	7,205,539	6,565,710	6,089,257	5,613,518	4,800,755	3,759,381	2,946,521	2,468,208	2,122,774	
46 Less Monthly ECAH Rider Revenue	(761,717)	(825,289)	(825,289)	(825,289)	(825,289)	(825,289)	(825,289)	(825,289)	(825,289)	(825,289)	(825,289)	(825,289)	
47 Less Monthly ECAH Rider Revenue	(761,717)	(825,289)	(825,289)	(825,289)	(825,289)	(825,289)	(825,289)	(825,289)	(825,289)	(825,289)	(825,289)	(825,289)	
48 Tariff Customer Ending Balance (\$)	7,776,500	7,926,943	7,105,622	6,380,250	5,740,421	5,263,968	4,788,229	4,350,257	3,934,092	3,771,232	3,292,919	2,947,485	
49 Interest	7,776,500	7,926,943	7,105,622	6,380,250	5,740,421	5,263,968	4,788,229	4,350,257	3,934,092	3,771,232	3,292,919	2,947,485	
50 Montanito Balancing Account (\$)													
51 Beginning Balance	13,170,906	12,862,491	12,463,847	12,108,832	11,795,426	11,375,129	10,842,555	10,369,766	9,863,373	9,441,593	8,936,411	8,459,204	
52 Less Monthly ECAH Rider Revenues	(289,268)	(309,213)	(323,362)	(332,362)	(342,946)	(354,127)	(366,400)	(378,673)	(390,946)	(403,219)	(415,492)	(427,765)	
53 Less Monthly ECAH Rider Revenues	(289,268)	(309,213)	(323,362)	(332,362)	(342,946)	(354,127)	(366,400)	(378,673)	(390,946)	(403,219)	(415,492)	(427,765)	
54 Interest	10,851	10,559	10,267	9,956	9,650	9,344	9,038	8,732	8,426	8,120	7,814	7,508	
55 Montanito Ending Balance (\$)	12,882,438	12,453,489	12,140,485	11,795,426	11,375,129	10,842,555	10,369,766	9,863,373	9,441,593	8,936,411	8,459,204	7,948,050	
56 Agrilan Balancing Account (\$)													
57 Beginning Balance	997,651	999,116	939,469	910,303	887,993	858,278	819,839	776,605	728,751	687,642	657,320	627,004	
58 Less Monthly ECAH Rider Revenues	(29,355)	(30,442)	(31,529)	(32,616)	(33,703)	(34,790)	(35,877)	(36,964)	(38,051)	(39,138)	(40,225)	(41,312)	
59 WLA Adjustment per Stipulated Agreement	819	795	770	746	722	698	674	650	626	602	578	554	
60 Agrilan Ending Balance (\$)	969,115	939,469	887,993	858,278	819,839	776,605	728,751	687,642	657,320	627,004	596,676	566,352	
61 Agrilan Ending Balance (\$)													
62 Total ECAH Deferral Balance	24,622,453	25,256,951	25,414,263	25,498,769	25,531,514	25,564,180	25,596,871	25,629,571	25,662,271	25,694,971	25,727,671	25,760,371	26,961,092

(1) Recovery of non-owned wind integration costs pending future rate cases.